Seismic characterization of naturally fractured reservoirs by double focusing Gaussian beams with limited seismic acquisition

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Summary

Fractured reservoirs represent important hydrocarbon reserves but are often associated with low recovery rate. The goal of increasing extraction of oil and gas from such reservoirs will be greatly increased by having information about subsurface fractures such as fracture orientation, fracture spacing, and fracture compliances. We have previously shown that, when seismic acquisition has full azimuth, a double focusing Gaussian beams (DFGB) method is effective at determining fracture orientations for multiple fracture sets, the fracture spacing of each fracture set (even if the fractures are irregularly spaced), and the relative fracture compliance of each fracture set as a function of position in the reservoir. This information can be used to build reservoir fluid flow models for enhanced oil recovery. Here, we investigate the resolving power of the DFGB method for the case of limited azimuth seismic acquisition. A numerical example shows that our method can provide spatially dependent information on fracture parameters using data collected in current marine seismic streamer surveys.

Introduction

Naturally fractured carbonate reservoirs occur worldwide and they account for the bulk of oil production. Fractures may provide essential porosity and permeability for fluid flow (Nelson, 2001). In the Mideast and Mexico, the bulk of the oil production is from fractured reservoirs. The fractured reservoirs are usually associated with low recovery factor. Characterizing the fracture network to obtain fracture orientation and spacing can provide important information to direct reservoir development. Fracture compliance, which measures how easily fracture surfaces slip against each other (tangential compliance) or how easily the fracture can be opened (normal compliance), is also important. In addition, knowledge of fracture orientations can provide constraints on the stress state of the field thus yielding better geo-mechanical models. Kang et al. (2011; 2013) have shown that if fracture plane orientation, spacing, and permeability are known as a function of position within a reservoir, one can better capture flow transport behavior in fractured media.

There are several existing methods for fracture characterization. Direct coring of the borehole or formation micro-imager (FMI) logging provides local information on the scale of inches. Extrapolating information from these measurements to positions away from the wellbore is difficult. In cases where a fracture intersects an uncased borehole, seismic stress waves generated by the surface or borehole sources can squeeze the fluid from the intersecting fracture into the borehole and excite or alter borehole tube waves, which can be used to place constraints on the compliance of a single fracture (Huang and Hunter, 1982; Beydoun *et al.*, 1984; Beydoun *et al.*, 1985; Li *et al.*, 1994; Kostek *et al.*, 1998a; Kostek *et al.*, 1998b; Bakku *et al.*, 2013). A fractured reservoir with aligned fractures whose spacing is much smaller than a wavelength (i.e. less than tenth of the wavelength) can be treated as an equivalent anisotropic medium (Assad *et al.*, 1992; Tatham *et al.*, 1992). In this context, available methods based on seismic anisotropy include the Amplitude-Versus-Azimuth (AVAz) analysis of reflected P waves (Ruger and Tsvankin, 1997; Johns *et al.*, 2008; Sabinin and Chichinina, 2008) or shear wave splitting analysis (Tatham *et al.*, 1992; Sayers, 2002; Vetri *et al.*, 2003; Rial *et al.*, 2005; Yang *et al.*, 2005; Verdon *et al.*, 2009). These methods usually require the assumption that there is a single set of parallel fractures. However, multiple sets of intersecting fractures are readily observed in the field and it is not clear how effective and stable those methods could be in chartacterizing fracture properties in such cases.

Fractures represent mechanical discontinuities that have the ability to scatter seismic waves. When the fracture spacing is large or fractures are clustered, the equivalent medium concept cannot be applied. Based on the azimuthal variation of the common-mid-point (CMP) stacks, Willis et al (2006) proposed a seismic scattering index method, which studies the azimuthal variation of the CMP stack for fracture-scattered signals. However, this method is less effective in distinguishing multiple sets of fractures.

Zheng et al. (2013b) proposed a new method which is based on the analysis of the interference of two Gaussian beams focused onto the fractured reservoir location; one beam is from the surface sources and the other is from the surface receivers. This method has been shown to be very effective in characterizing fractures in an orthogonal fracture network with constant fracture spacing but spatially variable fracture compliances. Recently, we also demonstrated the applicability of the method to the case of irregularly spaced fractures (Zheng *et al.*, 2013a). However, in both cases, we had the full seismic acquisition azimuth. In this abstract, we investigate the case of

azimuthally limited seismic acquisition aperture, which is more common in practice.

Examples

We consider a fractured reservoir (1) at a depth of about 1000 m in which fractures exist within a shear zone We consider an acquisition in which data are collected along an azimuth that is not parallel to the shear zone and is orthogonal to the dominant orientation of the fractures within the fracture system (Figure 2). Given the limited seismic acquisition, can we resolve these fractures at the reservoir depth?

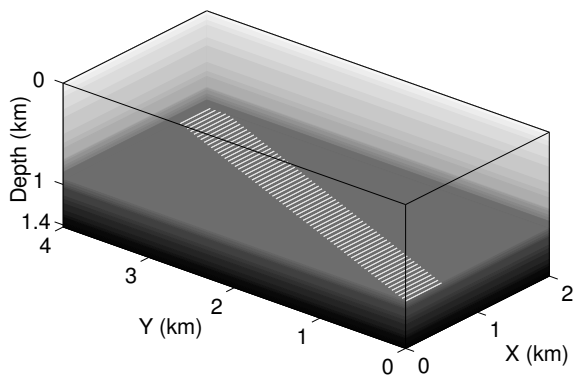

Figure 1: 3D model for the fractured reservoir. The fractures represent an extensional relay system due to shearing.

We perform a numerical example to investigate what information can be obtained about a fracture network from a somewhat conventional seismic acquisition. A fractured reservoir is embedded in a 3D layered model (Figure 1). There are 20 elastic layers above the fractured reservoir, which is located at a depth of 1000m. The thickness of the layer containing the fractures is 30m. The six seismic shot lines (streamers) are oriented perpendicular to the fractures(Figure 2). Shot lines are 3000 m long and sources are spaced at 40 m in the inline direction and 100 m in the crossline direction. The maximum offset that we use between the source and receiver is 2000 m.

All fractures are parallel to each other and have constant fracture spacing of 60 m. We simulate seismic shot gathers using a 3D elastic staggered grid finite-difference method (Coates and Schoenberg, 1995; Fang *et al.*, 2013). Fractures in the model are treated as linear-slip boundaries (Schoenberg, 1980). An absorbing boundary condition using perfectly matched layers (PML) is imposed on all sides of the model. The source time function is a Ricker with the central frequency 40 Hz. In our test, we simulated full elastic wave propagation in the model with 4C acquisition (i.e., pressure and 3-component particle velocities). However, in the double beam stacking we only used the pressure component recorded by the receivers at the surface. Thus, in this case, only the spatial variation of the normal compliance field can be determined.

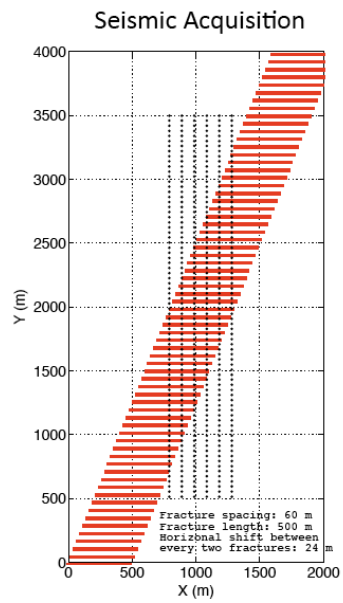

Figure 2: Map view of subsurface fracture network for the fractured reservoir. Red lines indicate fractures. All fractures are vertical. The fracture network has just one set of fractures with constant fracture compliance and spacing. The background model has 20 horizontal layers. Seismic sources (explosions) and acquisition streamers run parallel to the Y-direction over the center of the model (black dots). Source spacing is 40m and source line spacing 100m.

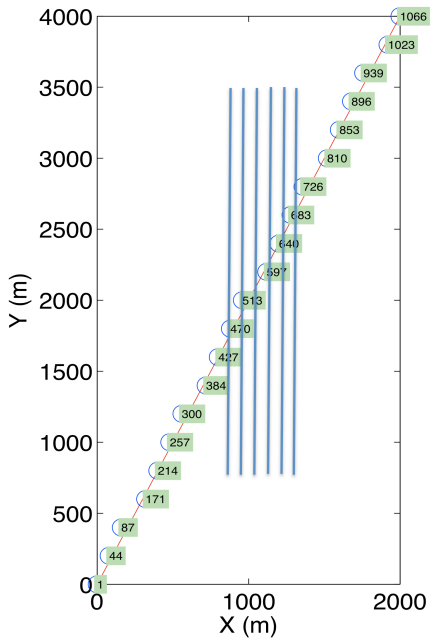

Figure 3: Map view of selected fracture targets to be characterized by DFGB. Target positions are numbered and numbers correspond to the results shown in Figure 4.

Since our method is target-oriented, we select a set of target locations for fracture characterization (3). We select target locations that range from directly beneath to well to the side of the acquisition survey as shown in Figure 3. To implement the double focusing Gaussian beam algorithm, for each target, we scan all possible fracture spacings from 40m to 120m and orientations from 0 to 180 degrees at a frequency of 40Hz as described by Zheng et al., (2013). Although using multiple frequencies can increase the detection robustness and mitigate the effects of noise on the results, we only show results for a single frequency since there is no noise in the synthetic data and results at different frequencies are the same.

At 40Hz, the *P* wavelength is about 75 m at the reservoir depth. We set the beam widths to be 80m, e.g., $w_s = w_g = 80m$.

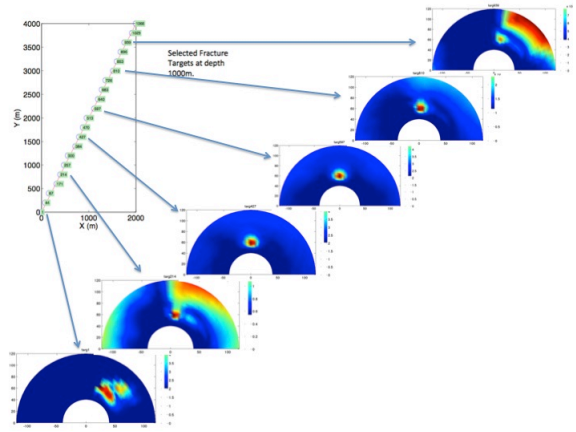

Figure 4. Double focusing Gaussian beam results $|\sigma|$ for different fracture locations in polar representation. The radius indicates the fracture spacing from 40m to 120m. The angle, counter-clock-wise from the positive horizontal axis, measures the pole orientation of the fracture. The color indicates focusing amplitude at the target for the double Gaussian beams.

Figure 4 shows the results for several selected target positions. Targets located beneath the survey, approximately targets 300 – 600, have good recovery of fracture orientation (East-West having poles trending North) and spacing. Targets located outside the acquisition region have relatively good recovery of fracture parameters. Only when targets are well outside the acquisition survey region does the recovery of fracture parameters become erroneous.

We thus find that for reservoir target regions within the shot lines our method can characterize the fracture orientation and spacing very faithfully. It is found by the DFGB that there is only one set of fracture system. The fracture planes are trending in the EW direction and the fracture spacing is spatially uniform, 60m.

The range of fracture orientations that can be resolved depends on the range of azimuths for beams that can be focused on a particular zone. Figure 5 illustrates this effect.

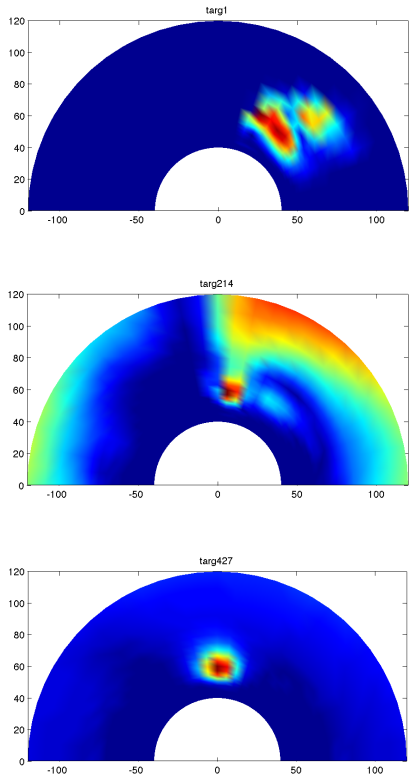

Figure 5: Double focusing Gaussian beam results for three particular targets (numbers 1, 214, and 427), which are the first three results from the lower left corner of Figure 4. For Target 1, which is located far outside the acquisition area (see Figure 3), the results are clearly in error. For Target 214, which is located near the edge of the acquisition area, the estimated fracture orientation and spacing has some error but is relatively accurate. For Target 427, which is located at the edge of the acquisition area, the estimates are excellent. As can be seen in Figure 4, within the acquisition area the results are excellent.

Conclusions

For full-azimuth seismic data , we have previously shown that the double focusing Gaussian beam method can characterize a fractured reservoir having a single or multiple fracture set even when fracture spacing is variable and relative compliance is spatially varying.

For the case where seismic acquisition does not allow a full range of azimuthal illumination on a target , it is still possible for our DFGB method to characterize the fracture parameters: orientation and spacing. In Figures 4 and 5 we see that excellent estimates (similar to those obtained with full azimuth data) are obtained within the acquisition coverage area where we are able to illuminate the reservoir target with a reasonably wide range of beam angles. Very good estimates are still possible outside the acquisition area, but those estimates degrade as we move further away due to more limited beam illumination. These results suggest that the DFGB method can provide accurate fracture parameter estimates over significant areas of a field even with limited azimuth seismic streamer data. With these parameters, one can build reservoir models and optimally place wells and drilling direction to maximize production.

Acknowledgments

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